Transmission Icing: A Physical Risk with a Physical Hedge

Hyde M. Merrill, *Fellow, IEEE,* and James W. Feltes, *Senior Member, IEEE*

Abstract**—**For 50 years US utilities used load and short-circuit currents to melt or prevent transmission line icing. This technique fell into disuse in the US during the last 50 years. Major recent ice storms caused many downed lines and much loss of customer load. Improved control and weather monitoring allow transmission-icing risks to be hedged without switching or otherwise jeopardizing system security. A careful risk analysis is needed to develop the right strategy.

Keywords**—**ice, power system operation, power system reliability, power system security, power transmission lines, power transmission meteorological factors, risk analysis, robustness

I. INTRODUCTION

A. Problem Statement

In most of Canada and in much of the USA, Europe, and Asia, ice can form on transmission lines. Ice can change the aerodynamics of the lines, causing galloping and short circuits. If enough ice forms, the weight can cause the lines to collapse. Thus icing can cause loss of load.

For example, Fig. 1 shows iso-ice contours for a storm that struck southern Quebec and northern New York in January 1998. In the hardest hit areas, with icing well beyond line design standards, every line was on the ground. A large area, including Montreal, was blacked out. Millions of people were without power, some for weeks.

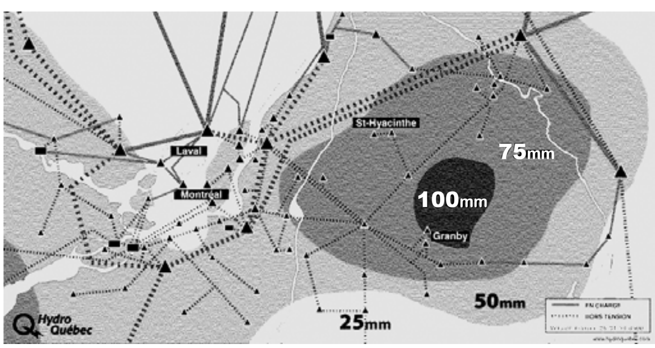

Fig. 1. Icing and downed lines (dashed) in Quebec, January 1998. Source: Hydro-Quebec.

Hyde M. Merrill is with Merrill Energy LLC, Salt Lake City, UT. James W. Feltes is with Siemens Power Transmission and Distribution Inc., Power Technologies International, Schenectady, NY.

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In this paper we attack the problem of preventing icing. This paper makes three contributions.

1. We show how redispatched load currents can prevent transmission icing, without the need for switching.[1]
2. This works because much less heat is required to prevent icing than to melt ice, and because available techniques can redispatch real and reactive flows.
3. Making this work requires careful modeling and risk management. We show how to do this.

B. Prior Work

Icing has been a problem since the infancy of our industry [1]. When conductor heating has been done, the practice usually has been to melt the ice once it formed.[2] This is done using short-circuit or load currents.

In the basic short-circuit current approach, the three phases at one end of a line are shorted together. This requires special equipment at what was sometimes called a sleet bus.

In the most common load-current approach, currents are redirected and concentrated by switching lines out of service.

Both methods require taking lines out of service when system vulnerability is already higher than normal. Both require cumbersome, pre-planned, and tricky switching operations. Both methods work [1].

In New England, for example, serious sleet trouble occurred in 1916. In November 1920 a five-day storm repeatedly broke conductors of a 4-mile 69 kV line. In this storm operators attempted with limited success to melt the ice using heating currents. The following year circuits with thawing connections survived a serious storm. After a 1924 storm, the New England Electric System extended thawing procedures to all vulnerable high voltage transmission lines. The procedures were used often – 202 times in one ten-year period. In 1952 NEES engineers reported that in the

[1] In our first half-century, de-icing currents generally were created by switching lines out of service. This was cumbersome and risky.
[2] In 1952 Smith and Wilder [1] said that Niagara Mohawk (New York) operating personnel were told that ice melting took from about twice to about six times the current required to prevent icing. The fact that melting required more energy than preventing icing was generally known. Apparently ice melting was more common because procedures were too cumbersome to take advantage of the favorable ice prevention window, and because of difficulty in knowing when icing would occur.

intervening years “no repetition of the early disasters has occurred.” The NEES procedures required participation of “over 40 men specifically assigned to these duties at 27 scattered locations [2].”

An Illinois utility used load and circulating currents to prevent icing, and short-circuit currents to melt ice. They also reconnected certain transformers to create phase differences. These provided circulating currents that were high enough to melt ice without having to take lines out of service [3].

A 1957 electrical engineering handbook says that “many companies” prevented ice formation by raising conductor temperature with current [4].

During the last 50 years US utilities have emphasized designing lines to withstand icing rather than melting or preventing ice [5]. The US power engineering literature on ice melting or prevention has been sparse since a group of papers was published in 1952, but a 1998 survey listed 30 ways to do it [6].

In recent decades considerable work has been done on developing models of the detailed physical phenomena of icing and melting [7], [8].

During this period there has been work on ice melting in Russia. For instance, one group wrote a paper in 1975 comparing the economics of various methods for protecting against icing [9]. In 1978 they published a paper on the costs of melting ice through switching operations [10]. A year later they discussed melting ice in shield wires [11].

There has been a lot of work in China on ice melting. For instance, one paper develops a decision analysis approach to switching [12].

An approach requiring significant additional equipment is to install a VAR source at one end of a line and a VAR sink at the other. Under icing conditions they are switched on, increasing the current in the line [13].

Since the 1998 ice storm there has been a great increase in work on icing at various Canadian institutions.

One approach to de-icing that would be fun to watch is to circulate pulses of very high (rated) current through circuits with bundled conductors. Electromechanical forces cause conductors in the bundles to bang together, knocking off the ice [14].

Deciding which lines to switch out of service on a rotating basis in order to concentrate currents enough to melt ice is a challenging optimization problem that has been attacked with dynamic programming [15].

A paper from the New York Power Authority (whose system was damaged in 1998) and Ice Engineering LLC, suggests using high frequency (8 kHz – 200 kHz) excitation. Coupled with the skin effect, this reportedly concentrates heating in the ice [16].

Apparently in some systems current operating practice in threatening weather is to unload the transmission system in anticipation of contingencies [17]. While in some conditions this is probably correct, reducing flows makes contingencies more likely to occur in icing conditions.

One recent paper suggests using currents to prevent icing rather than melting it [18]. This approach is dismissed by others because anti-icing “currents are not necessarily available on all lines, and could hardly be imposed simultaneously as part of a de-icing strategy [15].”

We feel that this last assessment is much too negative. We believe that our redispatching approach to ice prevention can protect many or most transmission lines, most of the time.

II. PROBLEM DEFINITION

A. When Does Icing Occur?

It has long been known that ice usually will form on transmission lines only when temperatures are between about –3°C and +2°C [4].

The classic paper on icing gives a delightfully clear description of the mechanism: icing tends to occur when temperatures have been below freezing, making conductors cold. If the air temperature above the ground rises (an inversion), then any precipitation falls through the warm air as rain and freezes on contact with the cold conductor. If the air above the conductor is too cold, the precipitation freezes in the air and does not stick to the conductor. Icing occurs when ambient temperatures are between about –3°C and +2°C. Wind velocities tend to be low when ice forms – between 8 and 9 miles per hour in one severe storm. Generally temperature drops and wind velocity increases after ice forms [19]. Other authors give independent but similar descriptions [1], [3], [20].

These conditions occur in Quebec a dozen times a year between November and March, but generally for brief periods. In 1998 they occurred three times without thawing – on January 5-6 from 18:00 to 08:00, on January 7-8 from 18:00 to 08:00, and on January 8-9 from morning to morning. The icing precipitation in the area ranged from 20 to 100 mm [21]. Incidentally, the Hydro-Quebec report on the ice storm says that the rain that strikes the transmission lines is actually super-cooled below freezing.

Recent tests in Quebec suggest that in-cloud icing occurs between –8°C and –0.5°C, with the maximum formation at –2.5°C. Icing from precipitation is said to occur between –5°C and 0°C, with the maximum at –2°C [22].

B. Why is Icing a Problem?

Ice can bring down lines. This is expensive to repair. The cost of clearing away and rebuilding, in emergency conditions, can exceed the original cost of the line.

Downed lines cause service interruptions. In 1972 an ice storm blacked out all of Quebec. In 1997 an ice storm blacked out the Lanaudiere region of Quebec. There was no cascading failure in the 1998 ice storm in Quebec or New York – the loss of load in both areas was due exclusively to loss of connection due to downed circuits. Neither substations nor power plants were damaged in 1998 [23].

III. ICE PREVENTION USING LOAD CURRENTS

A. Current Required

Clem's classic formula [4], [19] for the current, I, needed to prevent icing is:

$$I^2 = \frac{\theta\sqrt{dv}}{8.18R}\times 10^4 \qquad (1)$$

where θ is the temperature rise in degrees Celsius above ambient needed, R is the conductor resistance in ohms/mile at 20°C, d is the conductor diameter in inches, and v is wind velocity in miles per hour. The formula is valid for $v > 2$ mph.

Measurements and experiments over the years indicate that it is necessary to raise the conductor temperature by only a few degrees. Clem says that increasing the conductor temperature 9°C should be adequate [19]. Table I shows current required to prevent icing for a few conductor types and wind speeds.

An optimal power flow program can be used to redispatch the system to provide the currents needed in the vulnerable circuits. The redispatch can also be calculated using generation shift factors.

TABLE I
ICE-PREVENTION CURRENT, PER CONDUCTOR (θ = 9°C)

345 kV 795 MCM ACSR	*R (Ω/mile)* =	0.1129	
	d (inches) =	1.108	
v (mph) =	5	10	15
Amps needed	**479**	**570**	**630**
115 kV 336.4 MCM ACSR	R (Ω/mile) =	0.2668	
	d (inches) =	0.720	
v (mph) =	5	10	15
Amps needed	**280**	**333**	**368**
34.5 kV 4/0 ACSR	*R (Ω/mile)* =	0.4200	
	d (inches) =	0.563	
v (mph) =	5	10	15
Amps needed	**210**	**249**	**276**

B. Example – US System

In one test on data for a US system, we postulated icing in a region where the principal transmission consisted of two double-circuit 345-kV lines. The lines were two-conductor bundled 795 MCM ACSR with thermal ratings of about 1330 amps per conductor. The base-case off-peak flows were about 340 MW and 30 MVAR per circuit.

Shifting 1460 MW of generation raised the flows to 765 MW per circuit, or 640 amps per conductor. Table I shows that this should prevent icing. This is well within the thermal and first contingency ratings. It did not require heroic redispatch. We looked at an off-peak case because under those conditions we would have to make the greatest effort to get currents high enough.

What about redispatching VARS only, by switching taps and compensation and changing the generator excitation? Shipping VARS can raise I^2R losses. But systems are designed to operate with low VAR flows. Because of the power triangle, it would be hard to generate and absorb enough VARS to get the current high enough without redispatching real power.

IV. RISK: ICE PREVENTION VS. MELTING

It takes much more heat to melt ice than to prevent it forming. This is because the heat of fusion of water is high. In addition, a covering of ice diffuses the heat produced by current in the conductor and has more surface for cooling. It is therefore cheaper to prevent icing than to melt it after it forms. But if we are too aggressive or sloppy we can waste energy in conditions when ice wouldn't have formed.

For instance, suppose studies showed that, on the average, icing occurred for 14 hours in January for a particular utility. A correct but not very useful icing model ("Model 1") is

$$\Pr(icing) = 14/744 = 0.0188 \qquad (2)$$

where Pr(icing) is the probability of icing in a given hour.

Suppose that melting ice after it forms takes no more than, say, six times the energy required to prevent ice by preheating. With no information beyond Model 1, the best bet is to melt, not to preheat. We will next show that modeling icing better leads to better operating strategies.

A. Ice Prevention – Temperature Strategy

Fig. 2 is a distribution of hourly temperatures in Utica, NY, a city chosen at random, for January 2005. For 31% of the time (227 hours) the temperature was between –3°C and 2°C. Of course, the temperatures away from the airport weather station may be higher in some areas and lower in others.

In "Model 2," the probability of icing in a given hour is:

$$\Pr(icing) = \Pr(icing \mid T_{icing})\Pr(T_{icing} \mid T_{meas})\Pr(T_{meas}) \qquad (3)$$

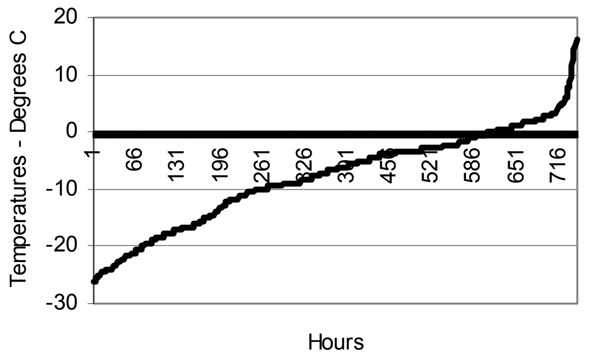

Fig. 2. Temperature duration curve, Utica NY, January 2005. Source: US National Climatic Data Center

In (3), T_{icing} is the temperature at which icing occurs (-3°C to +2°C) and T_{meas} is the temperature at the weather station. For icing to occur the temperature must be right. Since it must also be raining and there must be an inversion, assume that $\Pr(icing|\ T_{icing}) = 0.05$.

$\Pr(T_{icing}|T_{meas})$ is the probability of icing temperatures occurring *somewhere* nearby as a function of weather station temperature. This probability should be developed for actual use. For purposes of this paper, we assume Table II. $\Pr(T_{meas})$ is taken from Fig. 2. With these probabilities, the expected number of hours of icing in January 2005 is 14, as in Model 1.

TABLE II
ASSUMED PROBABILITY OF ICING TEMPERATURE SOMEWHERE NEARBY

Pr	T_{meas} (°C)
1.00	-4 to +3
0.30	-6 to -4 and +3 to +5
0.05	-8 to -6 and +5 to +7

For risk analysis using Model 2, we will use the five ice prevention rules or strategies of Table III. If icing occurs because we did not pre-heat, we will melt it after it forms, using the same current we would have used to prevent it forming. Depending on conditions, this melting may require between 1.5 and 6 times the energy (that is, the hours) that pre-heating would have required.

Figs. 3 and 4 show hours of ice-prevention heating and ice-melting heating for the five strategies of Table III. In Fig. 3 the preventive and melting heating are shown separately. In Fig. 4 they are combined to show the total heating.

TABLE III
ICE PREVENTION STRATEGIES

	Heat if T_{meas} (°C) =
0	no preheating
1	-0.5
2	-2.5 to +1.5
3	-4.5 to + 3.5
4	-8.5 to + 7.5

The highest melting curve is for melting that requires 6 times the energy needed to prevent icing. The other two are for melting that requires 3.5 or 1.5 times the ice prevention energy.

Strategy 1, the least aggressive ice prevention strategy, is useless – it doesn't do enough. The more aggressive strategies are wasteful because they preheat in too many hours when icing would not have occurred.

How can we lose, if it takes more energy to melt ice than to prevent it? We lose because Model 2 is too crude with regard to when icing will occur. The strategies heat the conductors whenever the temperature is near icing, regardless of whether there is precipitation or an inversion. These last two conditions don't always occur, so preheating is done unnecessarily.

B. Ice Prevention – Temperature and Precipitation Strategy

In Model 3, we change the icing model to:

$$\Pr(icing) = \Pr(icing|\ T_{icing} \cap rain)\Pr(T_{icing} \cap rain) \quad (4)$$

$$\Pr(T_{icing} \cap rain) = \Pr(T_{icing}\ |\ T_{meas})\Pr(T_{meas})\Pr(rain) \quad (5)$$

$$\Pr(rain) = \Pr(rain\ |\ precip_{meas})\Pr(precip_{meas}) \quad (6)$$

The precipitation $precip_{meas}$ is measured at the airport weather station. The question is whether it is raining *anywhere*. In this model we distinguish three kinds of measured precipitation: rain (including freezing fog), snow, or none (dry). We will assume that $\Pr(rain|precip_{meas})$ is 1.0 if the measured precipitation is rain, 0.2 if it is snow, and 0.05 if it is dry.

We will assume that $\Pr(icing|T_{icing}\cap rain) = 0.4$. Why is this value so low? Perhaps icing temperature and rain do not occur at the same place. Perhaps the rain is too light. Perhaps the wind is too high, etc. With Model 3, the expected value of icing hours in January 2005 is again 14.

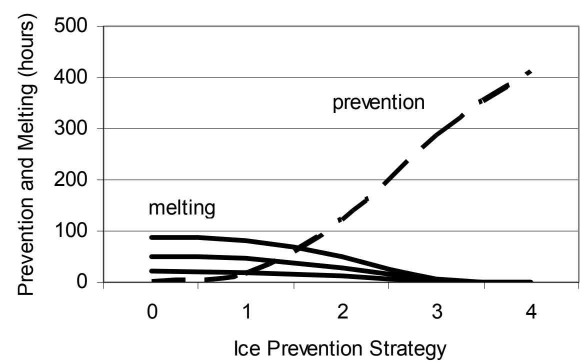

Fig. 3. With more aggressive prevention strategies, more energy is spent in preventing icing and less in melting it after it forms (Model 2).

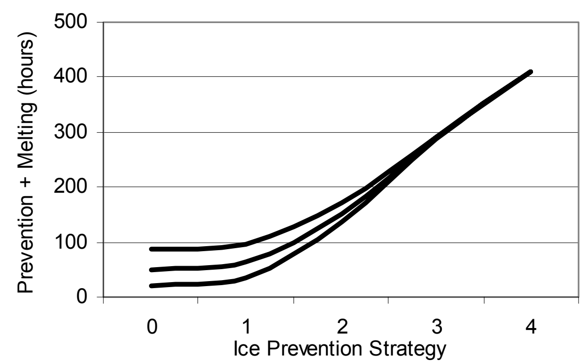

Fig. 4. Doing nothing uses less heat than bad ice prevention strategies.

For Model 3, we will do preventive heating using the five strategies of Table III, *but only if the airport reports rain (or freezing fog)*. As before, if ice forms because we did not pre-heat, we will melt it.

Fig. 5 shows that an ice prevention strategy beats doing nothing in moderate to heavy icing. As before, the two upper curves in Fig. 5 correspond to ice-melting multipliers of 6 and 3.5. The bottom curve is for light icing, with a melting multiplier of 1.5.

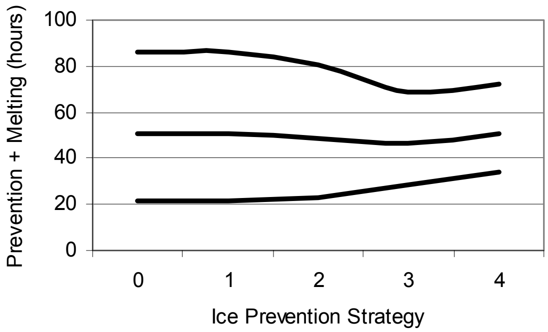

Fig. 5. Using a better model and strategy greatly reduces heating hours and makes ice prevention preheating worthwhile (Model 3).

C. Ice Prevention – Advanced Strategy

We have shown that as modeling and strategies improve, ice prevention becomes more practical. What is the theoretical limit?

If we knew that icing would be light, we would not bother to prevent it. We would only preheat when icing risked physical damage, that is, if it were moderate or heavy.

Suppose there were 5 hours of moderate or heavy icing conditions in a month. Suppose we did 5 hours of preventive heating. Suppose that our accuracy in identifying actual icing conditions ranged from 0% to 100%, with after-the-fact ice melting when we erred. The best we could do, with no errors, would be to heat for 5 hours. See Fig. 6, where the curves are for heavy and moderate icing.

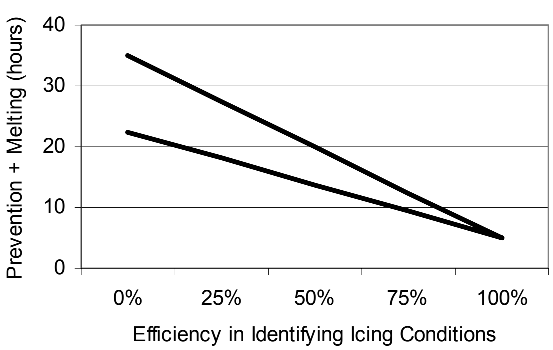

Fig. 6. A 100% efficient weather model and strategy minimize heating

IV. THE RISK OF. DOING NOTHING

Ice prevention using load currents costs money. The redispatch away from the optimal will be more costly than the normal economic dispatch based on generation costs or bid prices. In addition, system losses will likely increase and, of course, losses in the transmission path experiencing icing must increase – it is those losses that supply the additional heat to the conductor. In the case described above, redispatching 1460 MW increased losses in the targeted lines and elsewhere by about 150 MW.

Suppose that 1460 MW must be redispatched for 10 hours, implying good but imperfect modeling (Fig. 6). The redispatch cost (including most of the incremental losses) will be about the difference in locational marginal costs or prices on the two sides of the region needing increased flows. This difference is a random variable. Its value will vary from area to area and with time. In New York, typical differences between nearby zones are about US$10/MWh. At this rate, 10 hours of redispatch would cost US$146k.

If this cost were incurred monthly for four months per year, the yearly cost would be about US$584k.

These calculations are deliberately conservative. For instance, ice storms may occur when lines are moderately or heavily loaded, requiring less redispatch. The average power redispatched and its cost would likely be lower than our minimum-load worst case – perhaps on the order of US$200k-US$400k per year. See Table IV. Depending on operating rules, this cost probably flows directly to the customer without going through the transmission service provider's books.

TABLE IV
COSTS AND RISKS

Ice prevention	US$$10^5$ per year
System repairs	US$$10^6$-$10^8$ per incident
Societal costs	US$$10^6$-$$10^9$ per blackout
Government intervention	Not quantifiable

The cost of repairing a downed line depends on the nature of the damage, e.g. whether towers also collapsed, whether repair was urgent (in winter weather), etc. It might run from 50% to 150% of the construction cost of the line. Exclusive of right-of-way, a 345 kV line might cost on the order of US$500k/mile to build. On this basis it could cost in the range of US$2.5 million to US$7.5 million to rebuild a single ten-mile stretch.

Depending on the extent of the storm, he cost of repairing downed lines in a single storm probably would be in the millions to hundreds of millions of US dollars.

Customer costs of unserved load can be very high. Of course, the loss of a single line should not cause loss of load, except to radial load pockets. But we mentioned briefly three storms where many Hydro-Quebec customers lost power due to icing. In at least one of these storms New York customers lost service as well.

Societal costs of a local blackout might be on the order of a million US dollars. A major blackout is reported to cost society around a billion US dollars.

In addition to quantifiable customer costs, the public relations damage and subsequent government "help" in fixing perceived utility shortcomings can be costly.

Clearly, the risks of ignoring icing are very high. While the costs of ice-related outages can vary widely by area and circumstance, they are much higher than prevention costs. The costs of preventing icing damage are within a reasonable range.

V. EXTREME CONDITIONS

Would this approach have saved Montreal in 1998? The authors do not know. Few systems are designed to withstand a 100-year contingency, and everyone is a great quarterback on Monday morning. However . . .

Fig. 1 shows that the major intensity of the storm, and most of the damage, were south and east of Montreal. Fig. 7 shows the major transmission corridors. What would have happened with heavy flows in the directions shown by the arrows? (This could have been achieved by appropriate dispatching of the La Grande and Churchill Falls generation, some switching, and purchases / sales with US systems.)

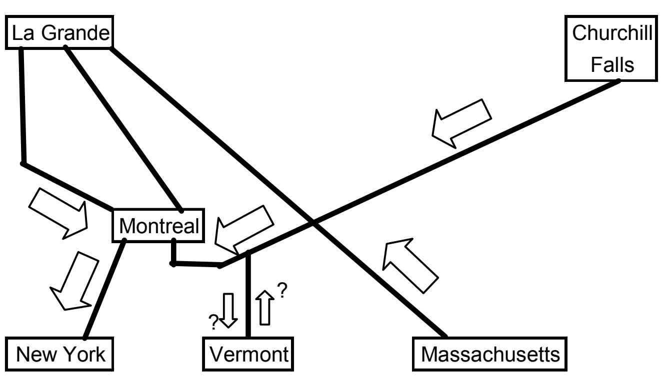

Fig. 7. Redispatching and arranging purchases / sales with the US would have concentrated flows in the region of heaviest icing, where most of the circuit damage occurred.

Service to about 700,000 customers was interrupted on January 6. There was some restoration on January 7, but an additional 800,000 customers lost power on January 8-10 [24].

Perhaps the icing on January 5-6 would have been reduced, with fewer or no lines down. Perhaps the ice would have been completely melted in the 24 hours before icing resumed on January 7-8. Perhaps the January 7-8 icing would have been reduced or melted in the 12 hours before the final blow the night of January 8. Perhaps, without the accumulation from previous days, and with continued heating, the lines would have withstood the icing that began that night.

Perhaps much less damage would have occurred to transmission circuits. Perhaps many fewer customers would have had service interrupted, and for less time.

Power flow and other studies would reveal if this approach would have worked in this extreme condition. The ice accumulation was well beyond design standards. Power company staff performed admirably during this storm and afterward. But an ice-prevention and melting strategy cannot be invented in real time. It must be planned in advance.

VI. SUBTRANSMISSION AND DISTRIBUTION

Radial subtransmission and distribution circuits represent a different problem, for four main reasons:

1. Redispatching generation has little effect on flows.
2. Operators have less remote control over lower voltage switching, etc.
3. The stakes are higher because the investment is higher.
4. Customer interruptions are more likely because redundancy is lower.

It may be possible to use load currents, with greater difficulty, to increase current flow on these circuits. Circuits might be reconfigured by switching to maximize heating. Another approach would be to artificially increase customer loads in emergency conditions. This could be done by radio and television announcements: "Turn up your (electric) heat and open your windows if you live in Area X. We won't bill you for it." In the future, if distributed generation becomes as prevalent as some predict, it could potentially be used to increase subtransmission and distribution circuit flows through dispatch control.

This would have to be researched carefully. We have not investigated whether terminal equipment would permit the necessary currents, whether voltages would decline unacceptably, etc. There are obvious legal and accounting issues that would need to be looked at. Another concern is the fraction of distribution system damage in ice storms due to broken tree limbs instead of iced conductors. This depends on geography and local utility trimming practices.

VII. CONCLUSIONS

In areas with cold winters, transmission line icing causes important risks. For many years, US utilities shifted current to increase losses, either to prevent icing or to melt ice. In the last 50 years, US utilities have relied on more stringent design standards. Nonetheless, a major Canadian utility, using similar standards, has suffered expensive damage on at least three recent occasions, with significant loss of load. In at least one of these storms, transmission lines collapsed in New York as well.

The ice preventing and melting techniques of yesteryear, and most ice-preventing and melting work done internationally today, require that lines be taken out of service. This is cumbersome, complex, and weakens the system during a storm.

Redispatching generation can hedge the risk by raising currents high enough to prevent icing, without switching.

Doing this requires careful modeling and risk analysis. The stakes are high enough, and the costs of the hedge low enough, to make it worthwhile.

VIII. ACKNOWLEDGMENTS

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IX. BIOGRAPHIES

Hyde M. Merrill (S'65, M'67, SM'81, F'93) is an electrical engineering graduate of the University of Utah and MIT (PhD 1972). He was with the American Electric Power Company for 7 years, spent a year at MIT on a visiting appointment, and worked for nearly 20 years at Power Technologies, Inc. He founded Merrill Energy LLC in 1998 to provide advanced capabilities in risk analysis and operations research to stakeholders in modern and traditional power markets. He is a member of the Eta Kappa Nu, Tau Beta Pi, and Sigma Xi engineering and scientific honorary societies, and is a registered professional engineer in New York.

James W. Feltes (M'78, SM'94) received his BS degree with honors in electrical engineering from Iowa State University and his MS degree in electrical engineering from Union College. He joined Power Technologies, Inc. (PTI), now part of Siemens Power Transmission and Distribution Inc., in 1979 and is currently a senior manager. At PTI, he has participated in many studies involving planning, analysis and design of transmission and distribution systems. He has also been involved in many projects involving development of models for studies of power system dynamics, testing to record equipment response, and model parameter derivation. He is a registered professional engineer in the state of New York. He is a member of the IEEE Power Engineering Society and Industry Applications Society, and is active on several IEEE committees and task forces.